Decision ___________________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority to Revise its Gas Rates and Tariffs to be Effective January 1, 2001. (U 39 G)	Application 00-04-002 (Filed April 3, 2000)

O P I N I O N

Summary

This Biennial Cost Allocation Proceeding (BCAP) was concluded by a settlement, which we adopt without modification. Based on the Settlement Agreement, transportation revenues from core customers will decrease by approximately $93 million annually; transportation revenues from noncore customers will decrease by approximately $20 million annually. A residential customer using 51 therms per month will see an average monthly bill decrease of $1.46, from $39.11 to $37.65 per month. The only increase under the Settlement Agreement is a slight .9% increase in rates for the core large commercial customers.

Background

In this BCAP, Pacific Gas and Electric Company (PG&E or the Company) seeks to adopt new forecast period costs and balancing account balances, to adopt a new gas demand forecast, to allocate its gas revenue requirement among customer classes, and to set rates to recover the revenue requirement for the two-year BCAP period. PG&E proposes an effective date of January 1, 2001.

PG&E's Gas Accord Decision (D.) 97-08-055 sets transmission, transmission-level customer access, and storage rates through 2002, and its General Rate Case (GRC) (Application (A.) 97-12-020, D.00-02-046) sets the distribution-level base revenue requirement. This BCAP allocates the distribution-level base revenue requirement and sets distribution and customer class charges.

PG&E originally requested authority to decrease its annual gas transportation revenue requirement by $132 million. PG&E proposed to reduce the transportation revenue requirement from core customers by approximately $107 million annually, and the transportation revenue requirement from noncore customers by approximately $25 million annually. The settlement lessened the decrease because of increased costs forecasted subsequent to filing this application.

PG&E's 2000 BCAP forecasts a 13% increase in throughput for core customers, a 1% decrease in throughput for noncore customers, and a 26% decrease for total system shrinkage. PG&E proposes a reduction of its current core portfolio allocation of 48 thousand decatherms (MDth) per day of annual Silverado capacity to 5 MDth per day to reflect the termination of PG&E's California gas contracts. PG&E further proposes an increase of 50 MDth per day of seasonal winter Baja capacity for the core portfolio to help mitigate the risks associated with peak demand events. PG&E also proposes that its Core Procurement Incentive Mechanism (CPIM) be modified to accommodate this capacity change.

PG&E presents long-run marginal costs of providing gas distribution service, including customer costs, based on the gas resource plan adopted in the

GRC decision. The marginal costs are used to allocate the distribution revenue requirement to customer classes. No changes to the marginal cost methodology are proposed in this BCAP proceeding.

The primary revenue requirement changes are changes in balancing account balances. PG&E proposes to change the balances for the transportation balancing accounts. These balances will be updated for the BCAP decision. PG&E proposes to use the revision date forecast of balances for setting the rate components to amortize all transportation balancing accounts.

The Gas Accord established the Balancing Charge Account (BCA) for tracking the revenues and costs associated with providing balancing service. PG&E proposes to allocate the balance in the BCA on an equal cents-per-therm basis to all end-use customers.

PG&E proposes a ratemaking change for the Core Fixed Cost Account (CFCA). Currently, 1/12 of the base revenues are booked monthly to the CFCA. PG&E proposes in this BCAP to use monthly factors to record the same base revenue requirement into the CFCA, to have a closer match of revenue requirement to revenues from customers.

PG&E proposes to reduce the bundled residential baseline tier differential by applying the 35% differential to the transportation components of residential rates, to help reduce the effect that the tier differential has on transportation revenue recovery.

PG&E proposes to reduce the core-averaging subsidy between the residential and small commercial classes by an additional 50% over the BCAP period. The deaveraging will be phased in over two years with an initial 25% core deaveraging upon implementation of the BCAP decision and an additional 25% core deaveraging in the second year of the BCAP.

PG&E provides compressed natural gas service for use in natural gas vehicles under the provisions of experimental rate Schedule G-NGV2. PG&E proposes an all-volumetric rate design for this service.

PG&E proposes a declining block rate structure for commercial and industrial customers served from the noncore industrial distribution rate schedule, to make rates more cost based and send better price signals to customers.

PG&E filed A.00-04-002 on April 3, 2000, along with prepared testimony. On May 3, 2000, PG&E submitted errata to its prepared testimony. On June 6, 2000, PG&E submitted "Revised Testimony Incorporating May Errata" (Revised Testimony). On August 11, 2000, the Office of Ratepayer Advocates (ORA) submitted its "Report on Pacific Gas and Electric Company's 2000 Biennial Cost Allocation Proceeding." On September 1, 2000, the following parties submitted intervenor testimony in this proceeding: California Cogeneration Council (CCC); California Industrial Group and California Manufacturers and Technology Association (CIG/CMTA); Department of General Service (DGS); Northern California Generation Coalition (NCGC); Southern Energy California, L.L.C. (SECal); and The Utility Reform Network (TURN). In compliance with Rule 51 of the Commission's Rules of Practice and Procedure, the Company convened noticed Settlement Conferences on September 20 and October 4 that were attended by the active parties.

Pursuant to Rule 51, the active parties (Settlement Parties)[1] move for approval of the attached Settlement Agreement (Settlement Agreement). The

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[1] PG&E; ORA; CCC; CIG/CMTA); Calpine; (DGS); (DENA); NCGC; SECal; and TURN.

motion asserts that this Settlement Agreement resolves all issues raised by parties in this docket. No issues require further litigation in this proceeding. (The Settlement Agreement is attached as Appendix A.) This motion addresses each of the issues raised by the parties in filed direct testimony. After first describing the terms of the Settlement Agreement, the motion demonstrates the following: (1) that the Settlement Agreement is in the public interest; (2) that the Settlement Agreement is an all party settlement, broadly supported by all active parties; (3) no hearings concerning this Settlement Agreement are necessary; (4) this Settlement Agreement is to be treated as a complete package and not as a collection of separate agreements on independent issues and should be approved without modification; and (5) the Settlement Agreement represents a settlement of all issues for purposes of this proceeding only and is not intended to establish precedent for any future proceeding.

I. The Terms of the Settlement Agreement

Parties raised a number of issues in response to positions filed by the Company in its Revised Testimony. The Settlement Agreement resolves all of the contested issues in this proceeding. The issues addressed in the Settlement Agreement are presented in the same chapter order as presented by the Company in its Revised Testimony. The Settlement Agreement also resolves issues raised by parties representing the interests of the electric generators that were not addressed in Revised Testimony. Illustrative class average rates that result from this Settlement Agreement are shown in Attachment 1 of Appendix A. The issues addressed in the Settlement Agreement are as follows:[2]

[2] See the Findings of Fact for a detailed description of each of the elements of the Settlement Agreement.

Chapter 3 – Gas Throughput Forecasts

Issue 3.1: Core and noncore throughput

Issue 3.2: Electric generation throughput forecast

The Settlement Parties agree to a lower core throughput forecast and higher electric generation throughput forecast than filed by PG&E. The noncore industrial and cogeneration throughput forecasts are unchanged from PG&E's Revised Testimony.

Chapter 4 – Gas Supply

Issue 4.1: Core Weighted Average Cost of Gas (WACOG)

The only issue raised by parties regarding gas supply was the level of the WACOG. Gas supply prices are set monthly for core procurement customers, however the WACOG has been used to calculate illustrative procurement rates and to derive bundled core rates in this proceeding. Since the Company filed its 2000 BCAP application in April 2000, gas supply costs have risen significantly. As discussed below, in considering core rate design proposals in this BCAP, the combined impact of supply and transportation rate changes on customers' bills has been taken into account. In order to better reflect the upward trend in gas supply costs, Settlement Parties agree to an illustrative average WACOG during the BCAP period of $3.50 per decatherm.

Chapter 5 – Marginal Capacity and Customer Costs

Issue 5.1: Refurbished Meters

Issue 5.2: Replacement Frequencies

Issue 5.3: Service, Regulator and Meter Labor Rates

Issue 5.4: Time to Design

Issue 5.5: Line Extension Allowance

Issue 5.6: Account Services Costs

Issue 5.7: General Plant Loading Factor

Issue 5.8: Marginal Cost Revenues

ORA and TURN filed testimony that proposed alternatives to the Company's filed positions on customer marginal costs, economic factors and the resulting marginal cost revenues. Instead of settling the individual issues, Settlement Parties agreed to a total marginal cost revenue and allocation. Parties agreed to settle all issues regarding marginal capacity and customer costs at the point that moves 65% from the marginal cost revenues calculated using the Company's marginal costs filed in its Revised Testimony towards the marginal cost revenues calculated using the marginal costs filed by ORA and TURN. The marginal cost revenues are calculated to reflect the settled throughput forecasts and are shown as Attachment 2 to Appendix A.

Chapter 6 – Revenue Requirements

Issue 6.1: Distribution Costs Allocable to Large Distribution

Issue 6.2: Core Fixed Cost Account (CFCA)

Issue 6.3: Tracking Core to Noncore Migration

Issue 6.4: Noncore Interim Relief Subaccount

Issue 6.5: Balancing Charge Account (BCA)

Settlement Parties agree that the distribution costs allocable to large distribution customers shall be recalculated based on the marginal cost revenues adopted in this proceeding, and allocated based on the methodology adopted in D.98-06-073.[3]

Settlement Parties agree to continue recording 1/12 of the core portion of the authorized base revenue amount in the CFCA each month. The revision date balance of the CFCA and the noncore interim relief subaccount will be amortized over 24 months, along with all other balancing accounts updated in this BCAP. The Settlement Parties further agree to eliminate the future tracking of core to noncore migration.

In this BCAP, Settlement Parties have agreed on a one-time basis, to allocate the revision date balance in the BCA 30% to core and 70% to noncore. Thereafter, the BCA will be allocated to customer classes on an equal cents per therm basis, which is approximately 39% to core and 61% to noncore based on throughput forecasts agreed to by Settlement Parties. The Settlement Parties further agree to offset the net cashout volume at the revision date[4], with a portion

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[3] The 1998 BCAP D.98-06-073 adopted Joint Testimony that reduces PG&E's annual distribution revenue requirement by 50% of the distribution revenue requirement allocable to noncore distribution service-level customers with annual loads in excess of 3 million therms from the end of the 1998 BCAP to the end of the Gas Accord. The Joint Testimony agreed to a 50% shareholder absorption of the scaled distribution marginal cost revenues allocable to these customers. (D.98-06-073, pp. 20-21.)

[4] As stated in PG&E's Revised Testimony (at 6-6), "there has been a greater quantity of negative (underdelivered) imbalance cashout volumes sold to customers compared to the positive (overdelivery) imbalance cashout volumes purchased from customers. This leaves a net quantity of approximately 1,350,000 Dth which may be procured in the future."

of gas that has been overcollected as transmission shrinkage gas on PG&E's system during the period of the Gas Accord.[5] By offsetting the net cashout volumes with accumulated shrinkage volumes, there will be no need for the Company to purchase gas to replace the net cashout volume.

Chapter 7 – Revenue Allocation and Rate Design

Issue 7.1: Core Deaveraging

Issue 7.2: Tier Differential

Issue 7.3: Procurement Rate

Issue 7.4: Industrial Distribution Declining Block Rate Component

Settlement Parties agree to 10% per year additional core deaveraging over the two year BCAP period. Settlement Parties further agree to increase the level of additional core deaveraging up to 15% in the second year (for a possible second year maximum of 25%) if the weighted average gas price, as indicated by the New York Mercantile Exchange (NYM) natural gas futures prices, falls below the agreed to target price of $3.75 per decatherm (Dth). An illustrative calculation of the weighted average NYM settle price is shown in Attachment 3-1 of Appendix A. The level of core deaveraging, in excess of 10%, that may occur in the second year of the BCAP for various weighted average NYM futures prices below $3.75/Dth is shown in Attachment 3-2 to Appendix A.

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[5] As PG&E indicated in its Revised Testimony (footnote 2 at 1-3), the Company has been addressing ways to better manage shrinkage on its system. The Commission recently approved Advice 2252-G effective October 1, 2000, to lower the transmission and distribution shrinkage allowances on an interim basis until shrinkage allowances are adopted in this BCAP. As indicated in that Advice filing, PG&E will address any further proposals through a separate mechanism.

Settlement Parties agree to calculate the differential between tier one and tier two residential rates at 70% of the transportation rate, rather than 35% of the bundled rate. This will prevent variations in the transportation rate differential as procurement rates change from month to month. At the average WACOG of $3.50 per decatherm agreed to by Settlement Parties in Issue 4.1, a 70% differential will result in an average bundled rate differential close to the level adopted in the prior BCAP.

Settlement Parties agree to eliminate the seasonal rate differential from core commercial procurement rates so that commercial customers procuring gas from the Company will pay the annual average cost of storage and pipeline capacity each month, rather than paying these costs only in their winter season procurement rates.

Settlement Parties agree to a four-tier declining block rate structure for the volumetric distribution component of the Schedule G-NT industrial distribution rate. The four-tier rate structure will be based on customers' annual usage during the 12 billing months ending with the current billing month, as shown in Attachment 4 to Appendix A.

Issues Raised by Electric Generation Interests

Issue EG.1: Cogeneration Gas Allowance (CGA)

Issue EG.2: Electric Generation Rate Segmentation

Issue EG.3: Backbone-Only Rate

Settlement Parties agree to increase the CGA by 10% from the current level of 9,683 to 10,681 Btu per kilowatt-hour (kWh). This is consistent with the Gas Accord Settlement which states that: "The cogenerator gas allowance is not to be determined by the Gas Accord, except that it will remain within 10% of 0.09683 th/kWh." (D.97-08-055, Appendix B, p. 43.) The distribution-level rates presented in Attachment 1 to Appendix A will be updated to reflect the cost to serve the additional volumes now qualifying for service under Schedule G-COG due to the increase in the CGA.

Settlement Parties agree that discussion regarding segmentation of the generation classes (G-COG and G-EG) shall be deferred to the Gas Accord II negotiations currently underway regarding the post-Gas Accord period commencing January 1, 2003. In addition, Southern Energy California agreed to withdraw its testimony regarding a backbone-only rate from this BCAP proceeding.

Settlement Parties agree that there are no issues remaining to be litigated in this proceeding.

II. The Public Interest

Prior to approving any settlement, the Commission must find that it is in the public interest. The Settlement Agreement, which adopts specific provisions consistent with prior Commission decisions, is in the public interest.

The Settlement Parties believe that this Settlement Agreement is in the public interest for one or more of the following reasons:

- The Settlement Parties represent the interests of all active parties, including core, noncore industrial and electric generation end-use customers and their representatives.
- Considerable time and resources are saved for all parties that would otherwise be spent in litigating these issues.
- The Settlement Agreement promotes rate certainty and stability.
- The Settlement Agreement treats core and noncore customers fairly.
- The Settlement Agreement reduces customer transportation rates sooner than if the case were litigated.

The Settlement Agreement is the result of discussion and negotiation, and represents a broad-based consensus on issues of concern to the Settlement Parties. Like many settlements, it is the result of compromises to accommodate and balance the interests of all parties. The Settlement Parties ask the Commission to approve the Settlement Agreement as a whole, without modification. We have reviewed the Settlement Agreement and find that, for the reasons set forth above, it is in the public interest and should be adopted without modification.

Comments

The draft decision of the Administrative Law Judge in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on _________, and reply comments were filed on ______.

Findings of Fact

1. Bundled core rates include an illustrative procurement component since actual procurement rates change monthly.

2. Backbone transmission, local transmission, storage and noncore transmission-level customer access charges included in core and noncore rates are set at the levels established in Gas Accord D.97-08-055 and not in this BCAP proceeding.

3. By the date set for comments on the draft decision in this BCAP, the Company will update and serve on all parties the rates to incorporate the current forecast period costs, balancing account balances and changes in cost and revenues determined in decisions by the Federal Energy Regulatory Commission or the California Public Utilities Commission. The Company will update final rates prior to implementation.

4. The testimony submitted by parties to this proceeding was entered into the record by stipulation.

5. The Settlement Agreement filed with the Commission on October 27, 2000, pursuant to Rule 51 resolves all of the contested issues in this BCAP.

6. The Settlement Agreement was supported by all of the active parties in the proceeding. The Settlement Parties are: CCC, CIG/CMTA, Calpine, DENA, NCGC, ORA, SECal, TURN, and PG&E. These parties represent the interests of end-use customers including core, noncore industrial and electric generation.

7. The Settlement Agreement was filed after all direct testimony was reviewed by parties, and substantial discovery between parties had occurred.

8. Considerable time and effort went into the negotiation and subsequent compromise on issues impacting each party's constituents.

9. The Settlement Parties believe that the Settlement Agreement is in the public interest as described in the Joint Motion for Approval of Pacific Gas and Electric Company 2000 BCAP Settlement Agreement.

10. The Settlement Agreement resolves all issues raised by parties to the BCAP, as follows:

A. Gas Throughput Forecasts

1.) Adopt ORA's average and cold year core throughput forecast. The agreed to average year throughput forecast for core customers is 306,965 MDth. The agreed to cold year throughput forecast is 335,246 MDth.

2.) Adopt the Company's forecast for noncore (Schedule G-NT) gas demand. The agreed to average year throughput forecast for G-NT customers is 195,336 MDth.

3.) Adopt an electric generation (EG) throughput forecast as the average of the proposals made by the Company, ORA and SECal. The average year throughput forecast for EG (net of cogeneration) is 178,743 MDth per year.

4.) Adopt the Company's average year cogeneration throughput forecast of 94,538 MDth.

B. Gas Supply

1.) Adopt a core WACOG of $3.50 / Dth for the limited purpose in this proceeding to illustrate procurement rates and derive bundled core rates.

C. Marginal Capacity and Customer Costs

1.) ORA and TURN filed testimony that proposed alternatives to the Company's filed positions on customer marginal costs, economic factors and the resulting marginal cost revenues. Instead of settling the individual issues, Settlement Parties agree to a total marginal cost revenue and allocation.

2.) Settlement Parties agree to settle all issues regarding marginal capacity and customer costs at a point that moves 65% from the marginal cost revenues calculated using the Company's marginal costs filed in its Revised Testimony towards the marginal cost revenues calculated using the marginal costs filed by ORA and TURN. Results are shown in Attachment 2 of the Settlement Agreement.

D. Revenue Requirement

1.) The distribution costs allocated to large distribution customers are recalculated based on marginal cost revenues adopted in this proceeding, and allocated based on the methodology adopted in D.98-06-073. The updated amount is $2.446 million per year compared to $2.046 million per year filed in the Company's Revised Testimony.

2.) All balancing account balances are amortized over 24 months using the revision date balances.

3.) The revenue requirement in the CFCA will be recorded using the current 1/12th per month methodology as described in Gas Preliminary Statement part D.

4.) Tracking the core to noncore migration revenue shortfall will end for the future BCAP period. The amount tracked in the current BCAP period is $1.511 million. The Company will transfer 18% of forecasted revenue shortfall at the revision date to noncore customers as proposed in the Company's Revised Testimony.

5.) Adopt ORA's recommendation to move the noncore interim relief subaccount of the CFCA into an appropriate subaccount of the Noncore Customer Class Charge Account (NCA).

6.) The BCA records revenues and costs associated with providing balancing service to customers under Gas Schedule G-BAL – Gas Balancing Service for Intrastate Transportation and penalties and credits under Gas Rule 14 – Capacity Allocation and Constraint of Natural Gas Service.

7) On a one-time basis in this BCAP, the revision date balance in the BCA will be allocated 70% to noncore and 30% to core customers. Thereafter, the balance in the BCA will be allocated to customer classes on an equal-cents-per-therm basis.

8.) As of January 31, 2000, there were significantly more negative (underdelivered) imbalance cashout volumes sold to customers compared to the positive (overdelivered) imbalance cashout volumes purchased from customers. The net cashout volume difference is approximately 1,350,000 decatherms.

9.) Adopt a one-time offset of the net cashout volume calculated at the revision date against a portion of the transmission shrinkage gas that has been collected from customers during the period of the Gas Accord. As a result of this offset, there is no need for the Company to purchase gas to replace this net cashout volume.

E. Revenue Allocation and Rates

1.) Reduce the core-averaging subsidy between the residential and small commercial classes by an additional 10% per year for each year of the BCAP period.

2.) Increase the level of additional core deaveraging up to 15% in the second year (for a possible second year maximum of 25%), if the weighted average gas price, as indicated by the NYM natural gas futures prices, falls below the agreed upon target price of $3.75/Dth. An illustrative calculation of the weighted average NYM price and the associated level of core deaveraging in excess of 10% that may occur in the second year of the BCAP is shown in Attachment 3 of the Settlement Agreement.

3.) The Company will file for the increase in core deaveraging prior to the second year of the BCAP, which will commence one year after the implementation date of the BCAP rates.

4.) Gas supply costs have risen significantly since the Company filed its application in this proceeding. The combined impact of supply and transportation rate changes on customers' bills has been considered in the Settlement Agreement.

5.) Calculate the differential between tier one and tier two residential rates at 70% of the transportation rate, rather than 35% of the bundled rate. At the average WACOG of $3.50 per decatherm agreed to in the Settlement Agreement, a 70% differential will result in an average bundled rate differential close to the level adopted in the prior BCAP.

6.) Allocate pipeline capacity costs using currently adopted methods.

7.) Commercial core procurement customers currently pay pipeline capacity costs in their winter season procurement rates.

8.) Eliminate the seasonal rate differential from core commercial procurement rates so that commercial customers procuring gas from the Company will pay the annual average cost of pipeline capacity each month. This is consistent with treatment of storage capacity costs pursuant to Gas OII D.00-05-009.

9.) Address changes to the allocation of core storage and pipeline capacity in Gas Accord II or the next BCAP.

10.) Adopt a four-tier declining block rate structure for the volumetric distribution rates as shown in Attachment 4 of the Settlement Agreement. The four-tier rate structure will be based on the customer's annual demand.

F. Issues Raised by Electric Generation Interests

1.) Adopt CCC's proposal to increase the CGA by 10% as provided for in the Gas Accord, from 9,683 Btu per kWh to 10,681 Btu per kWh.

2.) Based on preliminary analysis, increasing the CGA will shift 3 to 5% of the volumes currently served under core rate schedules and noncore Schedule G-NT to service under Schedule G-COG.

3.) In order to allocate costs based on the increase in the CGA, the Company will complete its cost study and adjust distribution-level rates in its final 2000 BCAP update to reflect the cost to serve the additional Schedule G-COG volumes.

4.) NCGC's proposal to segment electric generation (Schedule G-EG and G-COG) rates are not addressed in this BCAP and are deferred to the Gas Accord II settlement discussions.

5.) SECal's testimony proposing a backbone-only rate for customers' directly connected to the Company's backbone system is withdrawn from this BCAP.

11. The annual gas throughput forecasts by customer class, as summarized below, are reasonable and are adopted.

Class	**Average Year Throughput (MDth)**	**Cold Year Throughput (MDth)**
Core		
Residential	224,138	248,234
Commercial	81,914	86,099
Interdepartmental	120	120
Natural Gas Vehicle	793	793
Total Core	**306,965**	**335,246**
Noncore		
G-Net	195,336	195,702
Cogeneration	94,538	94,598
Electric Generation	178,743	178,297[6]
Enhanced Oil Recovery	36	36
Wholesale	4,327	4,529
Natural Gas Vehicle	820	820
Total Noncore	**473,800**	**473,982**

12. No party presented testimony contesting the Company's proposal to forecast its gas department uses and compressor fuel and lost and unaccounted

[6] To derive the cold year EG throughput forecast, the Company applied the ratio of the cold year to average year EG throughput forecast as filed in its Revised Testimony, to the average year EG throughput forecast as filed in the Settlement Agreement.

for gas demands as percents of monthly system throughput using its Gas System Operations' data. The methodology is deemed reasonable.

13. Shrinkage allowances are adopted, as follows:

	Core	**Noncore Distribution**	**Noncore Transmission**
Transmission	1.35%	1.35%	1.35%
Distribution	2.41%	.16%	N/A
Total	3.77%	1.51%	1.35%

14. No party in this proceeding opposed the Company's proposal to reduce the annual firm Silverado capacity originally allocated to the core portfolio in the Gas Accord from 48 MDth per day to 5 MDth per day and replace it with additional seasonal firm Baja capacity to transport gas from the Southwest from a total of 464 MDth per day to 514 MDth per day.

15. The reduction in Silverado capacity holdings to 5 MDth per day reflects the mutual termination of the Company's California gas contracts and is consistent with the Gas Accord. In order to mitigate the risks to core customers associated with peak demand events, the Company's core procurement department may increase its seasonal winter Baja capacity up to 50 MDth per day.

16. The change in core capacity holdings will result in a small total net annual savings to core portfolio customers in pipeline and As-available capacity costs.

17. The Company's proposal to revise its Silverado and Baja capacity holdings is reasonable and is adopted.

18. The Company's CPIM benchmark will be modified to incorporate the fixed and variable transportation cost adopted in this BCAP.

19. The Company's calculation of the brokerage fee revenue requirement is consistent with the provisions of Gas Accord D.97-08-055 and 1998 BCAP D.98-06-073 and is adopted for this BCAP period.

20. There was no testimony filed in opposition to the Company's forecast of carrying costs on gas in storage. The carrying costs are adopted as filed by the Company.

21. All issues raised by parties in this proceeding regarding marginal capacity and customer costs are resolved as part of the Settlement Agreement.

22. The Company's proposal to terminate the Core Canadian Demand Charge Subaccount of the Purchased Gas Account, the noncore Interstate Transition Cost Surcharge Subaccount and the Noncore Fixed Cost Account is reasonable and is adopted.

23. It is reasonable to segment the NCA into three subaccounts to ensure that the Company can properly track and allocate costs to the appropriate noncore customer classes.

24. The Company's proposal to return affiliate transfer fees, with interest, to customers based on base revenue allocation factors is reasonable and adopted. The fees are currently tracked in the Affiliate Transfer Fee Account for disposition in this BCAP.

25. The Company's proposal to allocate the residual balance in Gas Refund Plan 15 and 16 equal cents per therm to core and noncore customers is reasonable and adopted.

26. No party in this proceeding opposed the Company's proposal for an all-volumetric rate design for experimental Natural Gas Vehicle Schedule G-NGV2 rates. A volumetric rate makes it easier for natural gas vehicle owners to

compare the Company's fuel prices with the prices of alternative fuels and is adopted.

27. Proposed rates for a 24-month BCAP period as shown in Appendix B are reasonable and adopted.

Conclusions of Law

1. The Settlement Agreement was filed and served on all parties. No parties submitted comments or requested a hearing on the Settlement Agreement.

2. The Settlement Agreement is in the public interest and is approved without modification or hearings.

3. The BCAP period is 24 months beginning with the date on which rates are revised.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company shall file, no later than 30 days after the effective date of this order, revised tariff schedules which implement the adopted changes shown in Appendix B. The revised tariff schedules shall comply with General Order 96-A and shall apply to service rendered on or after their effective date.

2. This application is closed.

This order is effective today.

Dated ______________________________, at San Francisco, California.

SEE FORMAL FILE FOR

APPENDIX A and B